AESO SCADA Standard

Revision 1.0

FINAL

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APEGGA Permit to Practice P-8200

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1.0 Introduction

1.1 Purpose

The purpose of this standard is to define the AESO SCADA system requirements. These requirements are defined as:

a) the specific data needed by the AESO in fulfilling real time operational responsibilities;
b) the specific communication and associated requirements for transmitting the data from remote facilities to the AESO System Coordination Centre;
c) the operating requirements for the SCADA system to ensure availability of real time data.

1.2 Application

This SCADA standard applies to all facilities that will be directly connected to the AIES transmission system. It will be applied on a ***go forward basis***, that is the standard shall not be used as justification to retrofit or change existing SCADA systems presently applied to the AIES that are not compliant with this standard. The AESO reserves the right, on a case-by-case basis, to endorse retrofitting existing non compliant SCADA systems with this standard for those stations the AESO deems critical to the AIES.

This standard supersedes the technical requirements of OPP 003.1, Electric Facility Data and Communications for the Alberta Control Area, Issued 2003-07-28. OPP 003.1 will still exist as a document to define the policies and procedures to be followed.

This standard supersedes the Supervisory Control and Indication requirements that appear in the standards Technical Requirements for Connecting to the Alberta Interconnected Electric System (AIES) Transmission System, Parts 1, 2, & 3.

Additional SCADA requirements might be required by the local TFO and will be identified as part of a Joint Operating Agreement (JOP).

1.3 Definitions

The following terms are defined and apply to this standard:

ACE – Area Control Error– As defined by the ISO Rules[1].

[1] ISO Rules, Effective Oct. 14, 2004, Part 1 General, Definitions

AESO System Coordination Center (SCC) – The facility operated by AESO to manage the Alberta Control Area in a safe, reliable and efficient manor.

AGC – Automatic Generation Control– As defined by the ISO Rules.

AIES – Alberta Interconnected Electric System – As defined by the Electric Utilities Act.[2]

AIES Transmission System – As defined by the Electric Utilities Act.

Alberta Control Area – As defined by the ISO Rules.

Ancillary Service – As defined by the Electric Utilities Act. An ancillary service, according to the ISO Rules, includes one or more of the following:

a) Spinning reserve (SR)
b) Supplemental reserve generation (SUPG) or supplemental reserve load (SUPL)
c) Regulating reserve (RR)
d) Voltage support (VS)
e) Power system stabilizers (PSS)
f) Automatic voltage regulator (AVR)
g) Fast acting remedial action scheme for loads (RASL)
h) Black start capability (BSC)
i) Transmission must-run service (TMR)
j) Remedial action scheme for generators (RASG)

AVR – Automatic Voltage Regulator – As defined by the ISO Rules.

Communication System – A system or facility capable of providing information transfer between persons and equipment. The system usually consists of a collection of individual communication networks, transmission systems, relay stations, tributary stations, and terminal equipment capable of interconnection and interoperation so as to form an integrated whole. These individual components must serve a common purpose, be technically compatible, employ common procedures, respond to some form of control, and generally operate in unison.[3]

DCS – Distributed Control System – A system comprised of software, hardware, cabling, sensors, and activators, which is used to control and monitor equipment.[4]

DNP – Distributed Network Protocol – A communication protocol designed to achieve open, standards-based interoperability between substation computers, RTUs(Remote Terminal Units), IEDs (Intelligent Electronic

[2] Electric Utilities Act, 2003, Part1, Section 1
[3] Communications Standard Dictionary, 2nd Edition, Martin H. Weik
[4] IEEE Standard 1050-1996

Devices) and master stations (except inter-master station communications) for the electric utility industry.[5]

EMS – Energy Management System – A system used to monitor and control the Transmission System to facilitate the safe, reliable and efficient operation of the electrical grid.

Generation Capacity – The nameplate rating of the generator output at the generator terminals.

GPS – Global Positioning System - A satellite based global navigation system that consists of (a) a constellation of 24 satellites in orbit 11,000 nmi above the Earth, (b) several on-station (*i.e.,* in-orbit) spares, and (c) a ground-based control segment. The satellites transmit signals that are used for extremely accurate three-dimensional (latitude, longitude, and elevation) global navigation (position determination), and for the dissemination of precise time. GPS-derived position determination is based on the arrival times, at an appropriate receiver, of precisely timed signals from the satellites that are above the user's radio horizon.[6]

ICCP – Inter Control Center Protocol – A communication protocol designed for the efficient exchange of electric utility industry data.

IED – Intelligent Electronic Device – Any device incorporating one of more processors with the capability to receive or send data/control from or to an external source (e.g., electronic multifunction meters, digital relays, controllers).[7]

PSS – Power System Stabilizer – An electronic feedback system designed to enhance damping of power system oscillations in order to extend power transfer limits of the transmission and maintain reliable operation of the grid.[8]

RAS – Remedial Action Scheme – See SPS.

RBE – Report By Exception.

RTU – Remote Terminal Unit. – In SCADA systems, an RTU is a device installed at a remote location that collects data, codes the data into a format that is transmittable and transmits the data back to a central station, or master. An RTU also collects information from the master device and implements processes that are directed by the master. RTUs are equipped with input channels for sensing or metering, output channels for control, indication or alarms and a communications port.[9]

[5] Adapted from dnp.org
[6] Alliance for Telecommunication Industry Solutions (ATIS)
[7] IEEE 100 The Authoritative Dictionary of IEEE Standards Terms
[8] Based on WECC documentation
[9] Webopedia - Internet Dictionary

SCADA – Supervisory Control and Data Acquisition – A system of remote control and telemetry used to monitor and control the electric system.[10]

SPS – Special Protection System (Remedial Action Scheme) – An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding of (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.[11]

SVC - Static Var Compensator – A static (non-rotating) device that can vary the amount of reactive power either consumed or generated.

Transmission Line – As defined by the Electric Utilities Act.

1.4 Modifications

In respect to this standard the AESO must:

a) seek and consider the input and feedback of affected parties prior to making changes or additions to the standard;
b) make and manage all changes to this standard;
c) make this standard publicly available via the AESO website.

1.5 Requirement for Review

This standard expires and must be reviewed within five (5) years of the effective date shown on the cover page and given below. This standard shall stay in force during the review period, but shall automatically cease to have force twelve (12) months after the five (5) year expiry date.

The effective date of this standard is [September 6, 2004].

[10] NERC – Reliability Standards for the Bulk Electric Systems of North America, February 2005
[11] NERC – Reliability Standards for the Bulk Electric Systems of North America, February 2005

1.6 Document Change History

VERSION	DISCRIPTION	DATE
OPP 003.1	Existing Operating Policy	2003. 07. 28
Rev 0	Issued for Comment	2005.06.26
Rev 1	Final Version – All stakeholder comments addressed.	2005.09.06

2.0 SCADA System Overview

The AESO SCADA system is designed to fulfill the requirement of the safe, reliable and economic operation of the AIES. The operation of the AIES is directed by the AESO System Coordination Centre (SCC).

A simplified diagram of the AESO SCADA system is shown in Figure 2-1.The components of the SCADA system function together to provide a variety of essential services. These components are described next.

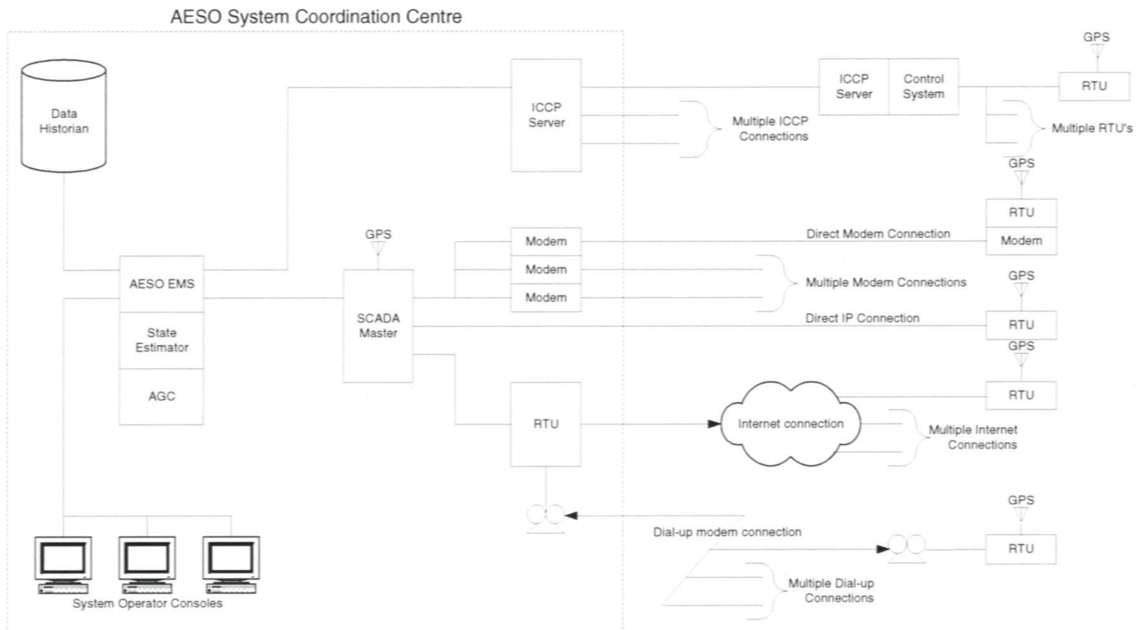


Figure 2-1 Simplified AESO SCADA System

2.1 Data Historian

The data historian contains a record of selected SCADA data and system data for retrieval at a later date. The data historian allows the viewing of data trends over long periods of time. Some of the uses of this data are: review of system events, sequence of events, determination of peak loads, forecasting using load flow records, and trending.

2.2 System Operator Consoles

The system operator consoles provide the system operators with the data and displays they require for operating the AIES Real time data is displayed in a variety of ways to allow operating decisions to be made. A variety of applications are used to assist with dispatch of generation and ancillary services, network analysis of power flow, and system security analysis for contingencies. These applications depend on the validity of the SCADA data to function properly.

2.3 AESO EMS System

The AESO EMS system collects all the SCADA data and arranges it for use by the various applications and systems that depend on the data. Data validation is done by the EMS system to ensure that the SCADA data is being received correctly and reliably.

2.4 State Estimator

The state estimator calculates and evaluates power flow on the system based on SCADA data and the system model. The results of the state estimator are used by system security applications, which provide real time contingency analysis and dispatcher load flows.

2.5 AGC System

The Automatic Generation Control (AGC) regulates the generation on the system to balance load, import/export, and generation. The AGC also calculates the Area Control Error (ACE) and adjusts generator output to maintain the desired import/export of energy.

2.6 ICCP Server

The ICCP Server serves as the data concentrator for SCADA data obtained from remote ICCP servers.

2.7 SCADA Master

The SCADA Master serves as a data concentrator for the SCADA data collected by the AESO from remote RTUs. The remote data is collected via a dedicated RTU for Internet connections and for Dial-up connections. Direct connections via modem or dedicated IP communications occur directly with the SCADA Master.

3.0 SCADA Data Point Requirement

This section identifies what facilities require visibility and what data points are required by the AESO for system visibility. MW and MVAR SCADA data shall be gathered independently of the revenue metering data. This includes CT cores, PT windings, and transducers such that the SCADA data can be used to verify the metering data. Revenue metering requirements are specified in Alberta Electric System Operator – Measurement System Standard, July 1, 2004.

The data point requirements for a new facility may require several of the following sections to be met in order to meet AESO's requirements. For example, a new power plant facility might include a substation and transmission line. The SCADA requirements would include the substation, transmission line, and power plant sections. Examples of data requirements can be found in Appendix A.

For measurements of voltage, real power, and reactive power, the measurement device shall take three phase measurements and provide a single value.

3.1 Power Plant

A facility with one or more generating units is considered a power plant. SCADA data points for power plants are required for real time operations as well as for generating unit modeling verification.

Power plant SCADA data points are dependent on the plant configuration. For plants where each generating unit has its own unit service the SCADA data points are shown in Configuration A. For plants where there is one station service that is used for several generating units the SCADA data points are shown in Configuration B. For plants with many small distributed units and collector system the SCADA data points are shown in Configuration C.

All other configurations will have to have the SCADA metering locations and data point requirement approved by the AESO.

Visibility is not required by AESO for power plants with a total output rating less than 5 MVA and not providing ancillary services.

3.1.1 Configuration A – Separate Unit Service for Each Unit

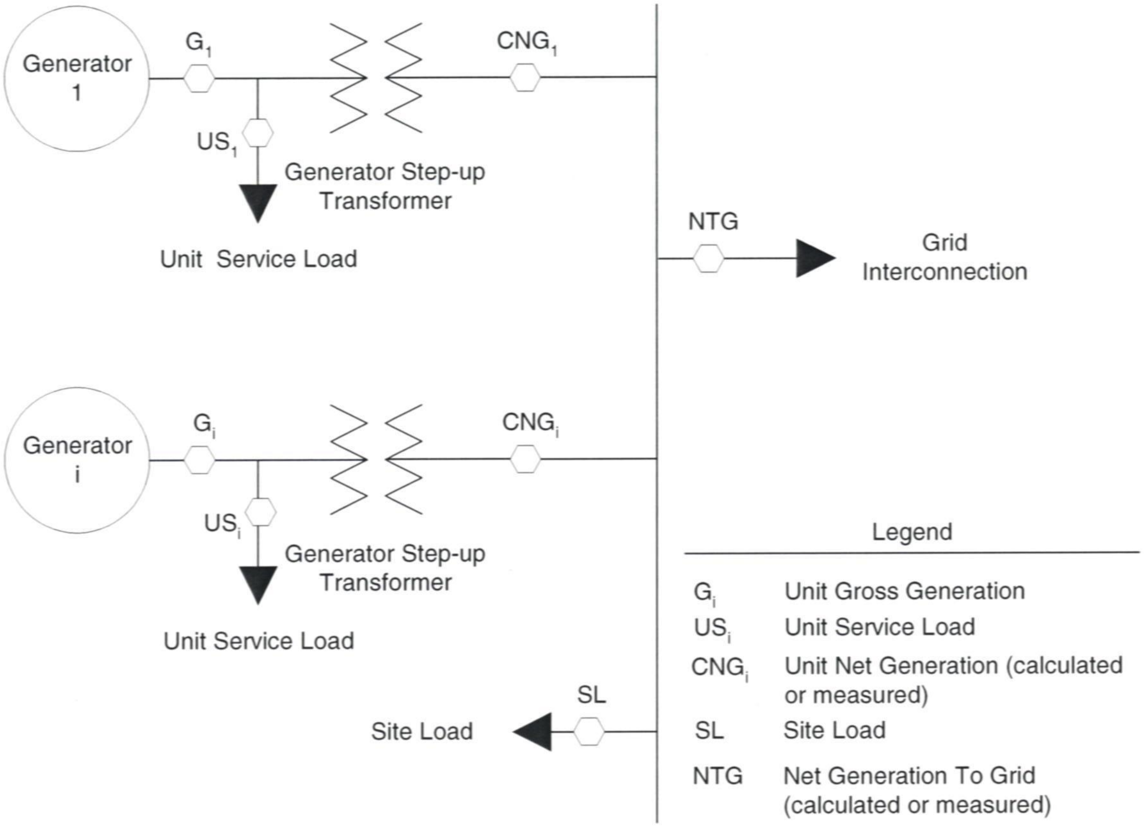


Figure 3-1 Power Plant Configuration A

Configuration A utilizes metering of Unit Gross Generation at each generator terminal (G_i in Figure 3-1 Power Plant Configuration A), and Unit Service Load for each generating unit (US_i in Figure 3-1).

The Unit Net Generation (CNG_i in Figure 3-1 Power Plant Configuration A) can be calculated by subtracting Unit Service Load (US_i) and step-up transformer losses from the Unit Gross Generation (G_i).

$$CNG_i = G_i - US_i - \text{Unit Transformer Losses}$$

Where Unit Net Generation (CNG_i in Figure 3-1 Power Plant Configuration A) is directly measured AESOs preference would be to receive the measured values.

Net Generation To Grid (NTG in Figure 3-1 Power Plant Configuration A) can be calculated by adding all Unit Net Generation (CNG_i) together and subtracting the Site Load (SL in Figure 3-1).

$$\mathrm{NTG} = \sum_{i=1}^{n} \mathrm{CNG}_i - \mathrm{SL}$$

Where Net Generation To Grid (NTG in Figure 3-1 Power Plant Configuration A) is directly measured AESOs preference would be to receive the measured values.

The Site Load (SL), although shown as a single value, may consist of one or more feeders and transformers. Either a single consolidated value may be provided or the individual feeder and transformer loads

For power plants with Configuration A rated 5 MVA or greater, the AESO requires the following SCADA data points:

Analog Data Points:

- Net Generation To Grid (NTG) power flow in MW including direction
- Net Generation To Grid (NTG) power flow in MVAR including direction
- Site Load (SL) power flow in MW
- Site Load (SL) power flow in MVAR
- Bus (plant) frequency in hertz (57-63 hertz) from generator bus if possible

For each generating unit within a power plant rated over 5 MVA the following SCADA data points are required:

Status Data Points:

- All breakers or switches associated with the connection of the generation through to the grid interconnection. This includes breakers, circuit switchers, motor operated air breaks and all other devices that can remotely control the connection / configuration of the generator to the grid. This does not include manually operated air breaks.
- Generator step-up transformer voltage regulator control auto/manual status, if the step-up transformer has a Load Tap Changer (LTC)
- Generator Power System Stabilizer (PSS) enabled/disabled status
- Generator excitation control/voltage regulation (AVR) automatic/manual status
- For generators with a dual mode controller:

- Generator excitation control voltage control mode status
- Generator excitation control power factor control mode status

Analog Data Points:

- Unit Net Generation (CNG_i) in MW including direction
- Unit Net Generation (CNG_i) in MVAR including direction
- Unit Gross Generation (G_i) in MW including direction
- Unit Gross Generation (G_i) in MVAR including direction
- Unit Service Load (USi) in MW including direction if capacity is greater than 0.5 MVA
- Unit Service Load (USi) in MVAR including direction if capacity is greater than 0.5 MVA
- The generator step-up transformer's tap position indication as an analog integer, if the step-up transformer has a Load Tap Changer (LTC)
- Generator voltage at the generator terminals or equivalent bus voltage in kV
- Voltage of the grid connection in kV (split / ring busses will require additional voltages to ensure connected voltage is available)

3.1.2 Configuration B – Single Station Service for Several Units

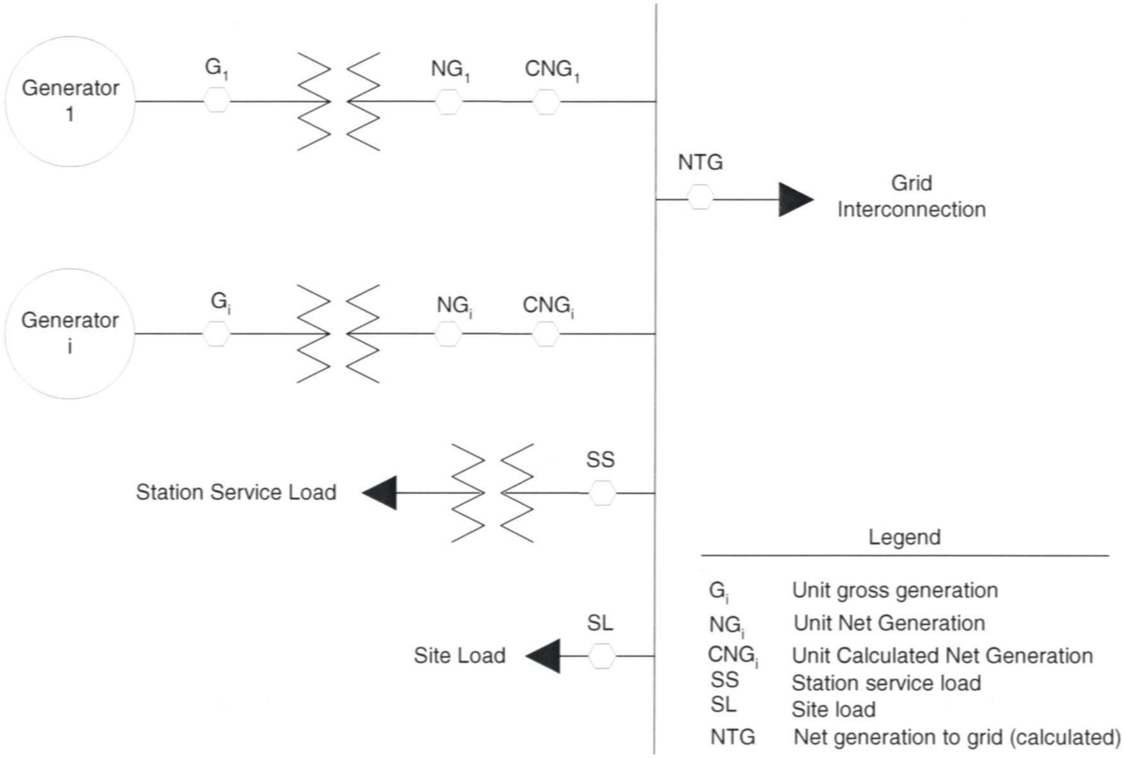


Figure 3- 2 Power Plant Configuration B

Configuration B utilizes metering of Unit Gross Generation at each generator terminal (G_i in Figure 3- 2 Power Plant Configuration B), and Station Service Load at the high-voltage side of the Station Service connection point (SS in Figure 3- 2 Power Plant Configuration B). The Unit Net Generation is calculated by subtracting a portion of the Station Service Load (SS) and step-up transformer losses from the Unit Gross Generation (G_i) for the unit. The portion of the Station Service Load (SS) to subtract is determined by the generation of the unit as a proportion of the total plant generation. The formula for calculating Unit Net Generation (CNG_i) is:

$$CNG_i = G_i - \frac{SS \times G_i}{\sum_{i=1}^{n} G_i} - \text{Unit Transformer Losses}$$

Where Unit Net Generation (NG_i in Figure 3-1 Power Plant Configuration B) is directly measured AESOs preference would be to receive the measured values. The formula for calculating Unit Net Generation (CNGi) would then be:

$$\mathrm{CNG_i} = \mathrm{NG_i} - \frac{\mathrm{SS} \times \mathrm{G_i}}{\sum_{i=1}^{n} \mathrm{G_i}}$$

Net Generation To Grid (NTG) is calculated by adding all Unit Net Generation (CNG_i) together and subtracting the Site Load (SL).

$$\mathrm{NTG} = \sum_{i=1}^{n} \mathrm{CNG}_i - \mathrm{SL}$$

Where Net Generation To Grid (NTG in Figure 3-1 Power Plant Configuration A) is directly measured AESOs preference would be to receive the measured values.

The Site Load (SL), although shown as a single value, may consist of one or more feeders and transformers. Either a single consolidated value may be provided or the individual feeder and transformer loads.

For power plants with configuration B rated 5 MVA or greater, the following SCADA data points are required:

Analog Data Points:

- Net Generation To Grid (NTG) power flow in MW including direction
- Net Generation To Grid (NTG) power flow in MVAR including direction
- Station Service Load (SS) power flow in MW
- Station Service Load (SS) power flow in MVAR
- Site Load (SL) power flow in MW
- Site Load (SL) power flow in MVAR
- Bus (plant) frequency in hertz (57-63 hertz) from generator bus if possible

For each generating unit within a power plant rated 5 MVA or greater the following SCADA data points are required:

Status Data Points:

- All breakers or switches associated with the connection of the generation through to the grid interconnection. This includes breakers, circuit switchers, motor operated air breaks and all other devices that can remotely control the connection / configuration of the generator to the grid. This does not include manually operated air breaks.

- Generator step-up transformer voltage regulator control auto/manual status
- Generator Power System Stabilizer (PSS) enabled/disabled status
- Generator excitation control/voltage regulation (AVR) automatic/manual status
- For generators with a dual mode controller:
    - Generator excitation control voltage control mode status
    - Generator excitation control power factor control mode status

Analog Data Points:

- Unit Net Generation (CNG_i) in MW including direction
- Unit Net Generation (CNG_i) in MVAR including direction
- Unit Gross Generation (G_i) in MW including direction
- Unit Gross Generation (G_i) in MVAR including direction
- The generator step-up transformer's tap position indication as an analog integer, if the step-up transformer has a Load Tap Changer (LTC)
- Generator voltage at the generator terminals or equivalent bus voltage in kV
- Voltage of the grid connection in kV (split / ring busses will require additional voltages to ensure connected voltage is available)

3.1.3 Configuration C – Collector System for Multiple Distributed Units

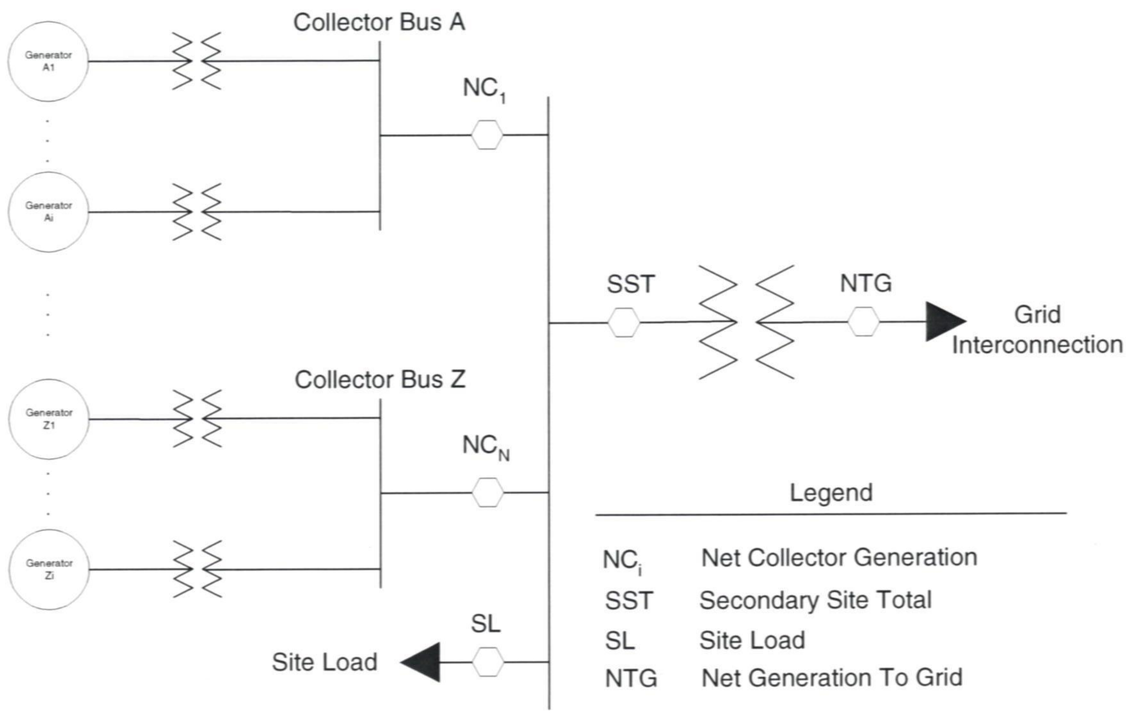


Figure 3- 3 Power Plant Configuration C

Configuration C utilizes metering of each Collector Bus (NC_N in Figure 3- 3), and Site Load (SL in Figure 3- 3), Secondary Site Total (SST in Figure 3- 3), and Net Generation to Grid (NTG in Figure 3- 3). This configuration typically is used by wind generation with many distributed units.

For power plants with Configuration C the AESO requires the following SCADA data points:

- Net Generation To Grid (NTG) power flow in MW including direction
- Net Generation To Grid (NTG) power flow in MVAR including direction
- Net Collector Generation (NC_{1-N}) power flow in MW
- Net Collector Generation (NC_{1-N}) power flow in MVAR
- Site Load (SL) power flow in MW
- Site Load (SL) power flow in MVAR
- Bus (plant) frequency in hertz (57-63 hertz)

- The facility step-up transformer's tap position indication as an analog integer, if the step-up transformer has a Load Tap Changer (LTC)
- Facility step-up transformer's low side voltage in kV
- Voltage of the grid connection in kV (split / ring busses will require additional voltages to ensure connected voltage is available)

Status Data Points:

- All breakers or switches associated with the connection of the collector bus through to the grid interconnection. This includes breakers, circuit switchers, motor operated air breaks and all other devices that can remotely control the connection / configuration of the collector bus to the grid. This does not include manually operated air breaks.
- Step-up transformer voltage regulator control auto/manual status
- Facility Power System Stabilizer (PSS) enabled/disabled status
- Facility excitation control/voltage regulation (AVR) automatic/manual status
- Facility excitation control voltage control mode status

3.1.4 Black Start Resource

Facilities providing black-start services shall have the following additional SCADA data points:

Analog Data Points:

- Bus (plant) frequency in hertz, with a range of at least 57 to 63 hertz, with an accuracy of +/- 0.012 hertz.

3.1.5 Regulating Reserve Resource

Operating requirements for Regulating Reserve Resources are defined in the standard Technical Requirements for Provision of Regulating Reserves. The additional SCADA data point requirements are:

Status Data Points:

- Generator regulating control enable/disable status

Analog Data Points:

- Unit Gross Generation (G_i) in MW including direction
- Generator high limit of the regulation range in MW any time it is changed by the Generating Unit Operator
- Generator low limit of the regulation range in MW any time it is changed by the Generating Unit Operator

For facilities using a set point for generator output control, the following data points are required:

Analog Data Points:

- The generator set point in MW from the generator control system

Regulating Reserve Resources must be able to receive the following control signals via SCADA:

Status Data Points:

- A status point will be provided indicating that the AESO's AGC has control of the resource

Analog Data Points:

- Set point in MW, updated every 2 seconds by AESO

NOTE: If multiple generating units are used to provide the full resource the signal provided by the AESO will be as if it were a single unit. I.E. A totalized expected MW output signal will be provided.

3.1.6 Spinning Reserve Resource

Operating requirements for Spinning Reserve Resources are defined in the standard Technical Requirements for Provision of Spinning Reserves. The additional SCADA data point requirements are:

Status Data Points:

- Spinning Reserve Resource circuit breaker status

Analog Data Points:

- Spinning Reserve Resource unit gross generation in MW including direction

3.1.7 *Supplemental Reserve Generation Resource*

Operating requirements for Supplemental Reserve Generation Resources are defined in the standard Technical Requirements for Provision of Supplemental Reserves by Generation Units. The additional SCADA data point requirements are:

Status Data Points:

- Supplemental Reserve Resource circuit breaker status

Analog Data Points:

- Unit Gross Generation (G_i) in MW including direction

3.1.8 *Special Protection Scheme for Generator*

Special Protection Schemes (SPS) are site specific and operate in a unique way so they require distinctive real time data and telecommunication specifications, The AESO will establish the additional data point and visibility requirements for these on a case-by-case basis.

The following data points may be required:

Status Data Points:

- SPS armed/disarmed status

- Operated alarm status

3.1.9 *Wind Power Facility*

In addition to the power plant requirements listed above, wind power facilities require the following SCADA data points:

Status Data Points:

- Voltage regulation system enable/disable status

Analog Data Points:

- Wind speed measured at rotor elevation in kilometers per hour

- Wind direction in degrees from true North, i.e. East = 90 degrees, West = 270 degrees

- Voltage Regulation System set point in kV

3.2 Substation

For each substation meeting at least one of the following criteria

a) Contains two or more buses operated above 60kV nominal voltage;*
b) Contains one or more buses operated above 200kV nominal voltage;*
c) Contains capacitor bank, reactor, SVC or synchronous condenser rated 5 MVAR or greater;
d) Connects 3 or more transmission lines above 60kV;
e) Supplies local (site) load, with normally energized site load equipment rated at 5 MVA or greater, that are offered for ancillary service or are included in RAS schemes;
f) Supplies local (site) load with normally energized site load equipment rated at 10 MVA or greater.
g) Supplies supplemental reserve load of 5MVA or greater;
h) Supplies load that is part of a special protection scheme.

* Two busses at the same voltage occur when there is a breakers, circuit switchers, motor operated air breaks and any other devices that can be remotely controlled that can isolate a portion of the substation and remain energized. This does not include manually operated air breaks.

The following data points are required for substation equipment:

3.2.1 Bus

Status Data Points:

- Circuit breaker, circuit switcher, motor operated air breaks, or other remotely controllable isolating device status

Analog Data Points:

- Bus voltage in kV line-to-line (ring busses will require a minimum of two voltage sources to ensure visibility during normally expected bus splitting or sectionalizing. These voltages can be provided by bus or line PT's.)

3.2.2 Transformer

For each transformer winding above 60 kV the following data points are required:

Status Data Points:

- Circuit breaker, circuit switcher, motor operated air breaks, or other controllable isolating device status

Analog Data Points:

- Power flow in MW including direction
- Power flow in MVAR including direction

Each point name must be prefixed with an H, L, or T representing High voltage, Low voltage, or Tertiary.

For each transformer with a load tap changer (LTC) meeting at least one of the following criteria

i) Regulating a bus whose voltage is above 60kV;
ii) Connecting a capacitor bank or reactor.

The following SCADA data points are required:

Status Data Points:

- Load Tap Changer (LTC) auto/manual status

Analog Data Points:

- Tap position indication as an analog integer

3.2.3 *Var Compensation Device*

For each capacitor bank, reactor, SVC, synchronous condenser, static Var controller, dynamic Var controller, or other Var device rated 5 MVAR or greater, the following data points are required:

Status Data Points:

- Control device status

Analog Data Points:

- Power flow in MVAR including direction

3.2.4 *Supplemental Reserve Load Resource*

Operating requirements for Supplemental Load Reserve Resources are defined in the standard Technical Requirements for Provision of Supplemental Reserves by Loads. The SCADA data point requirements are:

Status Data Points:

- Supplemental Reserve Resource circuit breaker status

Analog Data Points:

- Total Load Available in MW including direction

3.2.5 *Special Protection Scheme for Load*

Special Protection Scheme (SPS) for load are site specific and operate in a unique way so they require distinctive real time data and telecommunication specifications. The AESO will establish the data point and visibility requirements for these on a case-by-case basis.

The following data points may be required:

Status Data Points:

- RAS scheme circuit breaker, circuit switcher or other controllable isolating device status.
- Arming status of scheme
- RAS scheme operated status

Analog Data Points:

- Amount of load armed in MW
- Total RAS load available in MW

3.3 Transmission Line

For each transmission line above 60kV the following data points are required:

Status Data Points:

- Circuit breaker, circuit switcher, motor operated air break, or other controllable isolating device status

Analog Data Points:

- Power flow in MW including direction
- Power flow in MVAR including direction

For each transmission line above 200 kV the following data points are also required:

Analog Data Points:

- Line side voltage in kV (can be measured on one phase only)

For transmission lines above 60kV with tapped loads, power flow data must be provided so that the net power flow along the line can be determined. For a line with X terminals this requires power flow data from X-1 of the terminals. For example, a line with one tapped load (3 terminals) must provide power flow SCADA data from the substations at both ends of the line, or from one end plus the tap load substation (2 of 3 terminals).

For transmission line taps that are required to provide power flow data the following data points are required:

Status Data Points:

- Circuit breaker, circuit switcher, motorized air break, or other controllable isolating device status

Analog Data Points:

- Power flow in MW including direction
- Power flow in MVAR including direction

3.4 Interconnections to Power Systems Outside AIES

Interconnections to power systems located outside the Alberta Control Area require distinctive real time data and telecommunication specifications that depend on the configuration of the interconnection. The AESO will establish the data point and visibility requirements for these interconnections on a case-by-case basis.

3.5 RTU and Communications Circuit

For each RTU and associated communications circuits the following data points are required:

Status Data Points:

- IED to RTU communication fail alarm.
- RTU to TFO control center communication fail alarm if ICCP is utilized from the TFO to AESO.

4.0 SCADA Data Latency Time

SCADA data must reach the AESO EMS system in a timely and manageable manner. In order to deal with the vast amount of data required, and the limited communications and processing capability, SCADA data is divided into a number of groups, and each group is handled differently. More critical data is received and processed more frequently than less critical data. Another method of reducing the amount of data is to use report by exception (RBE). RBE allows the local RTU to poll the end devices for current data, and then report only changed data. All status points shall be reported by exception only. For analog data, report by exception may be utilized by reporting data that exceeds the specified deadband, reference to 5.5.

In this standard the latency time refers to the maximum elapsed time for an event in the field or end device to propagate through the SCADA system and be received by the AESO EMS. Facility SCADA systems should be designed such that data is scanned often enough to ensure this time is not exceeded. Complicated SCADA systems with several RTUs, data concentrators, and several levels of data processing shall consider all possible propagation delays to ensure the latency time specified is not exceeded.

4.1 Power Plant SCADA Latency Criteria

The following table identifies maximum allowable latency times for both status and analog values based on total power plant capacity.

Table 4-1 Power plant SCADA Latency Criteria

Maximum Latency	30 Seconds	15 Seconds	4 Seconds
Generation Capacity	≥ 5 MVA < 50 MVA	≥ 50 MVA < 300 MVA	≥ 300 MVA
Provide Regulating Reserve (Generator contracted amount)			≥ 15MVA
Provide Spinning Reserve (Generator contracted amount)		≥ 10 MVA < 300 MVA	≥ 300 MVA
Provide Supplemental Reserve (Generator contracted amount)	≥ 5 MVA < 50 MVA	≥ 50 MVA < 300 MVA	≥ 300 MVA
Provide RAS		All sizes	

Provide Black Start Service			All sizes

4.2 Substation SCADA Latency Criteria

The following table identifies maximum allowable latency times for both status and analog values.

Table 4-2 Substation SCADA Latency Criteria

Maximum Latency	**30 Seconds**	**15 Seconds**	**4 Seconds**
Bus	Two or more buses operated at 60kV or higher Connects 3 or more transmission lines above 60 kV	Any one bus operated above 200kV	
Transformer		Winding above 60kV	
Load tap changer (LTC) transformer	Regulates bus above 60kV Connects with capacitor bank or reactor		
Var Device	Switchable Var device (cap bank or reactor)	SVC, synchronous condenser, or other dynamic (variable) Var device	
Site Capacity	10MVA ≤ load< 50MVA ≥ 5MVA Supplemental Reserve Load or RAS scheme	≥ 50MVA	

4.3 Transmission Line SCADA Latency Criteria

The following table identifies maximum allowable latency times for both status and analog values.

Table 4-3 Transmission Line SCADA Latency Criteria

Maximum Latency	**30 Seconds**	**15 Seconds**	**4 Seconds**
Line to Line Voltage	> 60kV	>200 kV	

4.4 Integrity Scan

Where AESO communicates directly with an RTU the Integrity Scan is initiated by the AESO SCADA master on a periodic basis to confirm the communication path, RTU availability, and data integrity.

- For sites with only 30 second latency times the integrity scan is done at least once per day.
- For sites with 4 or 15 second latency times the integrity scan is done at least once per hour.

Where AESO communicates via ICCP and the data is RBE, the Integrity Scan is initiated by the AESO SCADA master on a periodic basis to confirm the integrity of the TFO's ICCP data in their database.

- For sites with only 30 second latency times the integrity scan is done at least once per hour.
- For sites with 4 or 15 second latency times the integrity scan is done at least every 10 minutes.

Table 4-4 Summary of Integrity Scan Time

	Direct AESO-RTU Communication	**ICCP Communications with RBE**
4 or 15 second Latency time	At least once per hour	At least once every 10 minutes
30 second Latency time	At least once per day	At least once per hour

5.0 Analog Real time Data Format Requirements

5.1 Number of Decimal Places

All directly connected SCADA systems shall provide analog values with at least one decimal place. All analog values communicated via ICCP will utilize protocol accuracy levels.

5.2 Scaling for Transducers

Transducer analogs shall be scaled such that the maximum value returned shall be between 120 and 200% of the nominal equipment rating (e.g. 600MVA line 800-1200 MW and 800-1200 MVar maximum value). Voltage transducers shall be scaled to a maximum of 120% nominal voltage rating.

Generators that can sync condense or motor (effectively run negative) the minimum shall be between 120 and 200% of the lowest operating condition.

5.3 Measurement Accuracy

Per NERC's requirements[12] the minimum values for Automatic Generation Control (AGC) measuring devices which are used in the calculation of Area Control Error (ACE) which may include generators providing regulating reserve and system tie lines are as follows:

Device	Accuracy
Digital frequency transducer	≤ 0.001 Hz
MW, MVAR, and voltage transducer	≤0.25 % of full scale
Remote terminal unit	≤0.25 % of full scale
Potential transformer	≤0.30 % of full scale
Current transformer	≤0.30 % of full scale

Unless stated otherwise in the project functional specification all other facilities are required to provide data within +/-2% of rated maximum values (full scale) with a resolution of 0.5%.

5.4 Deadband

Report by exception analog data is reported only when a deadband is exceeded. Deadbands may be used for analog SCADA values to reduce the amount of data transferred and thereby facilitate fast data updates.

The specified deadband is for a move from the last reported value in either direction (increase or decrease). For moves outside of the deadband the RTU

[12] NERC Standard BAL-005-0 Requirement 17.

shall report the new value at the next scan time. The same value will be reported if the value moves beyond the deadband limit, but returns again to its original value before the next scan. Buffered or stored data is not required.

When used to report changes to analog values the deadbands shall be as shown in Table 5-1.

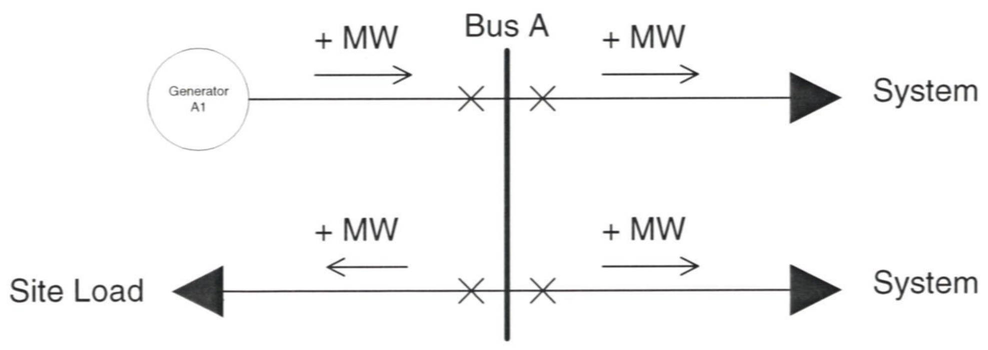
Table 5-1: Allowable Dead-Bands for Analog Report by Exception

Value	Allowable Deadband
MW without Ancillary Services	1 MW from 0 to 200MW, 0.5% above 200 MW
MW with Ancillary Services	0.5% from 0 to 200MW, 1MW above 200MW
MVAR	1 MVAR from 0 to 200MVAR, 0.5% above 200 MVAR
kV	0.1 kV from 0 to 20kV, 0.5% of nominal voltage above 20kV
LTC tap position	0 (no deadband allowed)
Wind speed	3 km per hour
Wind direction	5 degrees

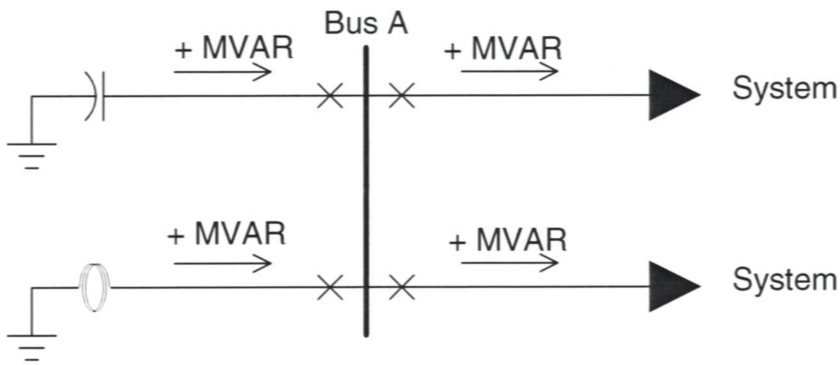
5.5 Polarity (Sign) Convention

Power flow analogs are to be reported with the sign convention of positive power flow being out from a bus. The only exception to this will be generators and shunts that are directly connected to a bus.

Example 1:



Example 2:



Power flows in the opposite direction shall be reported as negative numbers.

6.0 SCADA System Communications Requirement

The facility owner must provide all the necessary hardware and software and make all of the necessary arrangements so that the visibility points will be collected and transmitted to the AESO System Coordination Center as required. The transmission of this information shall be done using one of the methods (i.e., combination of protocol and medium) specified in this section. Refer to Figure 2-1for an overview of the SCADA system.

6.1 Communication Diagram

The facility owner shall provide a simplified communication block diagram for communication troubleshooting purposes detailing the communication path from its AESO connection point to the RTU or other device that is communicating with the electrical equipment in the field. If the facility is connecting to an existing ICCP connection, the diagram should show the connection from the existing ICCP server to the RTU or other field communicating device. The average and maximum expected time delay in communicating to the field RTU or other communicating device shall be provided.

Intermediary devices such as PLCs, DCS, computer systems, or other RTUs in the path will be shown in the diagram and the average and maximum expected time delays will be shown between each intermediary device. For security purposes device addressing shall not be provided on these diagrams.

It is the responsibility of the facility owner to provide written or electronic notification in advance of making changes to any communication equipment that is documented on the communication diagram. The notice shall include an updated communication diagram, complete with updated expected time delays. A final communication diagram shall be provided, complete with verified time delays after the changes are complete.

6.2 ICCP Connections

For larger facilities, or owners with multiple facilities and a central control center, the ICCP connection provides a single high-capacity communication connection for large amounts of data to be exchanged. The AESO will provide and maintain the ICCP connection point at the AESO System Coordination Center. In addition the AESO will provide and maintain an additional ICCP connection point at the Backup Control Center. The facility owner will provide and maintain the communications links and the ICCP interface point, including all connected devices to connect to these two locations. The communication link shall be IP based using a dedicated non-shared carrier.

The ICCP protocol is provided on the following communications medium:

a) Asynchronous Transfer Mode (ATM);
b) Frame relay.

6.3 Communication Redundancy

For centers with a combined load and generation of greater than 1000 MVA redundant communication circuits are required to the AESO System Coordination Center. Communication circuits are also required to the AESO backup coordination center.

For generators providing Ancillary Services, providers must ensure that their data is made available to the AESO backup coordination center as well as the primary coordination center.

6.4 Direct Connection via Modem

For facilities where a direct connection is utilized the AESO will provide and maintain a modem at the AESO System Control Center. The facility owner will provide and maintain the direct connection, modem, and RTU at the facility.

The DNP 3.0 protocol shall be used for direct connection via modem. The AESO shall be the master device, and the remote RTU shall be the slave device. The AESO shall provide the DNP addressing to be used.

6.5 Internet IP Connections

For facilities with internet access the AESO will provide and maintain an IP address and will poll the remote RTU's for updates. The facility owner will provide and maintain an internet connection and the remote RTU.

DNP 3.0 protocol shall be used for the internet connection. The AESO shall be the master device, and the remote RTU shall be the slave device. The AESO shall provide the DNP addressing to be used.

Internet connections are suitable only for sites not requiring 4 or 15 second latency times.

6.6 Direct IP Connections

For facilities with direct IP communications the AESO will provide and maintain an IP address and will poll the remote RTU's for updates. The facility owner will provide and maintain an IP connection and the remote RTU.

The DNP 3.0 protocol shall be used for the IP connection. The AESO shall be the master device, and the remote RTU shall be the slave device. The AESO shall provide the DNP addressing to be used.

6.7 Dial-up Modem Connection

For remotely-located facilities with cellular dial-up availability AESO shall provide and maintain a dial-up modem at the AESO System Control Center. The facility owner shall provide and maintain the dial-up connection, dial-up modem, and RTU at the facility.

The DNP 3 protocol shall be used for the dial-up modem connection. The AESO shall be the master device, and the remote RTU shall be the slave device. The AESO shall provide the DNP addressing to be used.

Dial-up modem Connection is suitable only for sites not requiring 4 or 15 second latency times.

6.8 IPP Use of TFO Communication Systems

This portion is presently under discussion with Altalink and ATCO who presently have GFO's utilizing their facilities. Once resolved, this standard will be updated. If you are interested in joining these discussions please contact Dan Shield at 403 539-2502.

7.0 Time Synchronization and Time Stamped Events

In order to perform post event analysis and to comply with WECC guidelines, AESO requires accurate time stamped power system quantities and events. Modern devices such as digital fault recorders, protective relays, event recorders, dynamic disturbance monitors, and SCADA systems are all capable of utilizing an externally generated time code for synchronizing their internal clocks.

For facilities that meet at least one of the following requirements

a) transmission stations 100 kV and above;

b) generating plants rated 30MVA and above;

c) control centers.

an external GPS based signal shall be utilized to provided 1ms time stamped event accuracy.

Time stamped events will be communicated real time back to AESO via the SCADA system.

8.0 SCADA System Operation Requirement

8.1 Designated Party

In the process of carrying out its real time operational functions and duties, AESO needs the cooperation and assistance of all parties interested in the development, commissioning, operation, maintenance and marketing of facilities located within the Alberta Control Area. To that end, facility owners should determine and designate a specific entity (if not themselves) that will carry out, those functions identified in this document. This designated party shall communicate in writing to the AESO its acceptance to fulfill the obligations of the designated party as specified in this standard.

8.2 Responsibilities of the Designated Party

During the period when the facility operates interconnected to the electrical network of the Alberta Control Area, the designated party must ensure that the facility provide, without unreasonable interruptions, all the data required by the AESO System Coordination Center, as specified in this standard.

The designated party is also responsible for communicating SCADA data point modifications, additions, and deletions to the AESO.

8.3 SCADA Data Availability Specification

The following table has the minimum percentage availability and maximum unavailability in hours per year for SCADA facilities. The required mean time to repair is also shown.

Table 8-1 Availability Requirements for SCADA Data Based on the Required Visibility Level

<table>
<tr><th colspan="2" rowspan="2">Visibility Level</th><th rowspan="2">Availability (%)</th><th colspan="2">Upper Limit of Acceptable Values</th></tr>
<tr><th>Unavailability (hrs off/year)</th><th>Expected Mean Time to Repair</th></tr>
<tr><td colspan="2">Facilities with 4 second latency requirements</td><td>99.7</td><td>26.3</td><td>4 hours</td></tr>
<tr><td rowspan="2">Facilities with 15 or 30 second latency requirements</td><td>With ancillary services</td><td>99.7</td><td>26.3</td><td>4 hours</td></tr>
<tr><td>Without ancillary services</td><td>98.0</td><td>175.2</td><td>2 business days</td></tr>
</table>

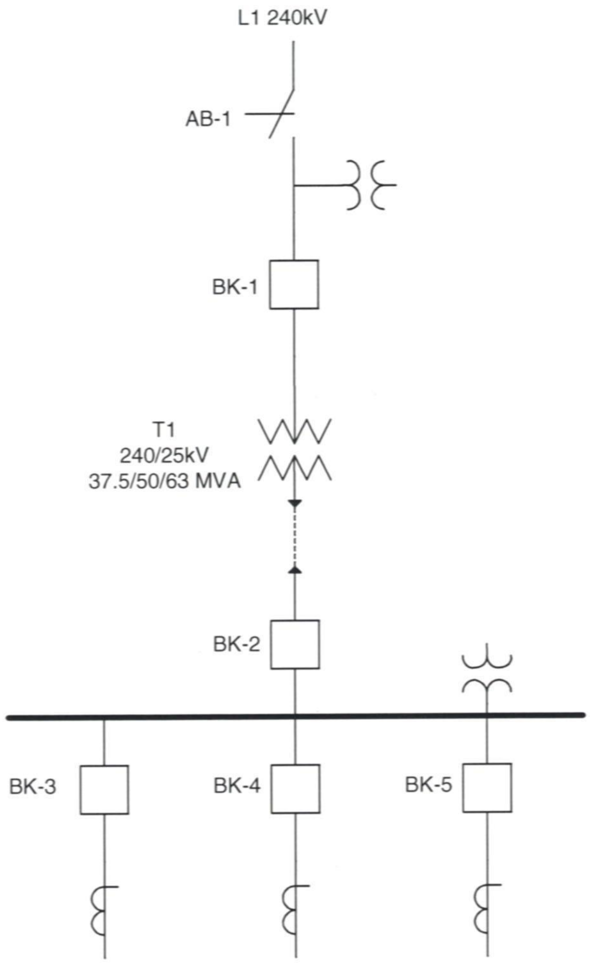
8.4 SCADA System Testing

AESO requires that SCADA data be verified back to the AESO System Coordination Center against the applicable SCADA requirements within this standard. AESO acknowledges that it is difficult to test certain equipment in all possible configurations and under all possible conditions, to this end AESO will work with the facility owner to test those configurations and conditions that are reasonable to test. Final testing requirements are at the discretion of AESO.

In addition to new equipment, AESO retains the right to request testing of modified equipment and configurations to ensure that SCADA requirements are met. This includes the right to request retesting of equipment or a site should the metering data become suspect. When possible testing will be coordinated with facility owners maintenance schedule.

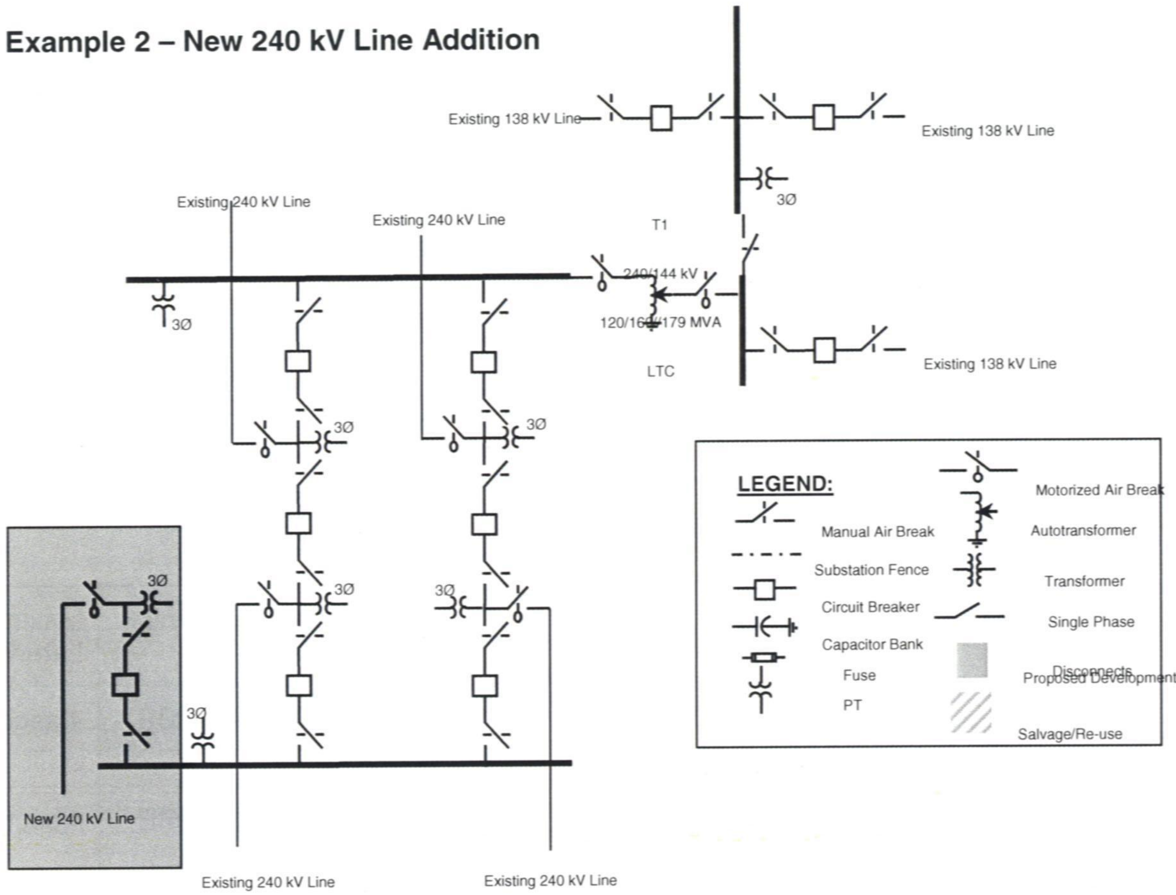
Appendix A – Examples of Typical SCADA Requirements

Example #1 – Industrial Substation Addition



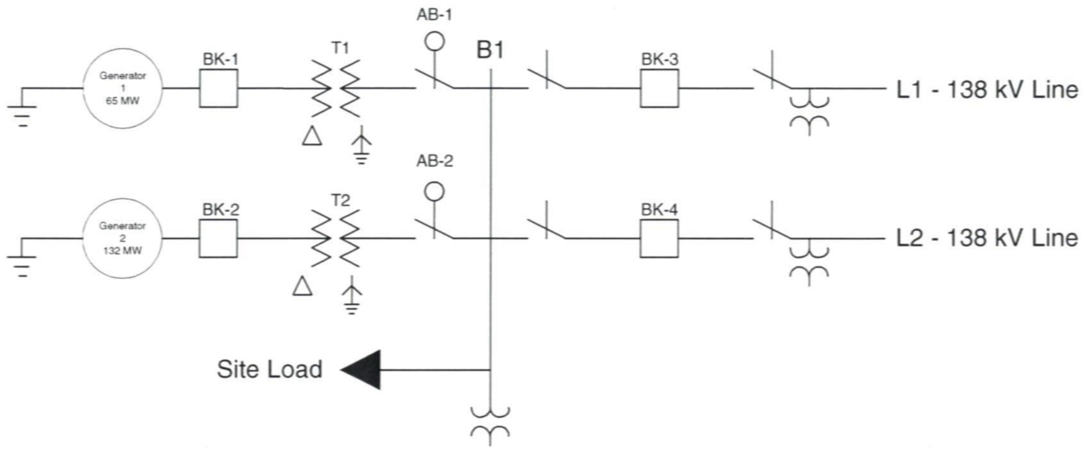
Device	Status / Analog	Units	Maximum Latency Time
Breaker BK-1	Status point	RBE	15 seconds
TFMR T1 Voltage Regulator auto / manual	Status point	RBE	15 second
TFMR T1	Analog	MW	15 seconds
TFMR T1	Analog	MVAR	15 seconds
TFMR T1 Tap Position	Analog	1-17	15 seconds
240 kV Bus Voltage	Analog	kV	15 seconds
Communication fail	Status point	RBE	15 second

Example 2 – New 240 kV Line Addition



Device	Status / Analog	Units	Maximum Latency Time
New breaker	Status point	RBE	15 seconds
Motorized air break	Status point	RBE	15 seconds
Line	Analog	MW	15 seconds
Line	Analog	MVAR	15 seconds
Line side PT	Analog	kV	15 seconds
Communication fail	Status point	RBE	15 second

Example 3 – Generators Providing Regulating Reserve



Device	Status / Analog	Units	Maximum Latency Time
Breaker BK-1	Status point	RBE	4 seconds
Breaker BK-2	Status point	RBE	4 seconds
Breaker BK-3	Status point	RBE	4 seconds
Breaker BK-4	Status point	RBE	4 seconds
Air Break AB-1	Status point	RBE	4 seconds
Air Break AB-2	Status point	RBE	4 seconds
TFMR 1 Voltage Regulator auto / manual	Status point	RBE	4 second
TFMR 2 Voltage Regulator auto / manual	Status point	RBE	4 second
Power System Stabilizer Enabled	Status point	RBE	4 second
Generator Excitation Voltage	Status	RBE	4 seconds

Regulation – auto / manual	Point		
G1 Net Generation	Analog	MW	4 seconds
G1 Net Generation	Analog	MVAR	4 seconds
G1 Gross Generation	Analog	MW	4 seconds
G1 Gross Generation	Analog	MVAR	4 seconds
G2 Net Generation	Analog	MW	4 seconds
G2 Net Generation	Analog	MVAR	4 seconds
G2 Gross Generation	Analog	MW	4 seconds
G2 Gross Generation	Analog	MVAR	4 seconds
Net to Grid	Analog	MW	4 seconds
Net to Grid	Analog	MVAR	4 seconds
Site Load	Analog	MW	4 seconds
Site Load	Analog	MVAR	4 seconds
T1 Tap Position	Analog	1-17	4 seconds
T2 Tap Position	Analog	1-17	4 seconds
G1 Voltage	Analog	kV	4 seconds
G2 Voltage	Analog	kV	4 seconds
Bus 1 Voltage	Analog	kV	4 seconds
Bus Frequency	Analog	Hz	4 second
L1 Voltage	Analog	kV	4 second
L2 Voltage	Analog	kV	4 second
L1	Analog	MW	4 second
L1	Analog	MVAR	4 second
L2	Analog	MW	4 second

L2	Analog	MVAR	4 second
Communication fail	Status point	RBE	4 second